UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Oil and Gas and Sulphur Operations in the Outer Continental Shelf — Pipelines and Pipeline Rights-of-Way	)))	Docket No. RIN 1010-AD11

COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Pursuant to the Proposed Rule making notice ("Proposed Rule") issued by the U.S. Department of Interior ("DOI") Minerals Management Service ("MMS") on October 2, 2007, 73 Fed. Reg. 56441 (Oct. 3, 2008), the Interstate Natural Gas Association of America ("INGAA") submits the following comments on MMS's proposals to revise and update regulations governing the design and operation of continental shelf ("OCS") pipelines.

EXECUTIVE SUMMARY

The Proposed Rule completely revises the MMS regulations governing pipeline right-of-ways and operations in the OCS.

INGAA is a non-profit trade association that represents the interstate natural gas pipeline industry. A number of INGAA's members operate right-of-way ("ROW") pipelines as defined under MMS regulations, 30 C.F.R. § 250.105. Other members operate or have affiliates that operate "lease term pipelines" as defined under MMS regulations. *Id*. Most of these members' OCS operations are presently subject to comprehensive safety regulation by the U.S. Department of Transportation ("DOT") Pipeline and Hazardous Material Safety Administration ("PHMSA"). *See generally* 49 C.F.R. Parts 190-192, 198, 199. To put matters in perspective, of the 33,000 miles of pipeline in the Gulf of Mexico, approximately 14,000 miles (42%) are natural gas pipelines that are managed in accordance with DOT pipeline safety regulations for design, construction, operation and maintenance.

From the perspective of INGAA's DOT-regulated offshore pipelines, the Proposed Rule is open to widely varying interpretations. The preferred reading is that the proposed regulations are not intended to apply to DOT-regulated offshore pipelines. This reading is consistent with DOI's authority under the Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331, *et seq*. ("OCSLA") and the December 10, 1996, Memorandum of Understanding ("MOU") that has defined and apportioned DOI and DOT jurisdiction over OCS pipelines for years. This reading is also supported by MMS's proposed jurisdictional regulations, suggested for codification at 30 C.F.R. §§ 205.1003 and 205.1004, as well as the Proposed Rule's impact statement under Executive Order No. 12866. Finally, this reading avoids jurisdictional confusion and overlap, with competing and possibly conflicting requirements. INGAA urges MMS to clarify that the Proposed Rule is intended to apply only to pipelines falling under DOI jurisdiction using the standards defined in proposed regulations 30 C.F.R. §§ 205.1003 and 205.1004.

While urging a reading that acknowledges and maintains DOT jurisdiction, some language in the Proposed Rule nevertheless suggests MMS intends to apply the new regulations to <u>all</u> pipelines, including those currently subject to DOT regulation. If and to the extent this is the intended scope of the Proposed Rule, INGAA objects to the regulations on legal and practical grounds. Universally applying the regulations to all OCS pipelines, whether DOT-regulated or not, would exceed DOI's authority under the OSCLA and would amount to a unilateral breach of the MOU. Moreover, in a number of cases the proposed regulations exceed, depart from, or conflict with current DOT regulations, imposing a costly compliance nightmare on pipelines that have been in compliance with prevailing federal requirements.

Finally, speaking for both DOT- and DOI-jurisdictional pipelines, INGAA objects to several of the proposed regulations on substantive grounds. As a general matter, the regulations impose design specifications instead of setting performance standards that could be met by more than one design. The effect is to impose specific technologies where the regulatory goal could be achieved through more economical means. In several specifics, the regulations impose requirements more stringent than their DOT counterparts, without demonstrating why the DOT standard is insufficient. As detailed below, the overall impact of the proposed regulations is to impose compliance costs far above what is necessary to achieve the intended regulatory objective.

GENERAL COMMENTS

I. WHILE THE PREFERRED READING OF THE PROPOSED RULE WOULD EXCLUDE DOT-REGULATED PIPELINES, THE LANGUAGE IS AMBIGUOUS AND SHOULD BE CLARIFIED.

The issue is captured and illustrated by a single word: "all."

Several passages in the Proposed Rule suggest that the proposed regulations are intended to apply only to pipelines that are not already subject to DOT jurisdiction. The clearest indication that DOT-jurisdictional pipelines are to be excluded occurs in the proposed jurisdictional regulations:

Sec. 1003 Which departments have jurisdiction over OCS pipelines?

An OCS pipeline is under the jurisdiction of either [DOI] or [DOT]

Sec. 1004 What are the criteria for determining jurisdiction?

(a) DOI jurisdiction criteria. An OCS pipeline is under DOI jurisdiction if it is:

- (1) A lease term pipeline <u>that is not subject to regulation under 49 CFR parts 192 and 195</u>, and does not cross into state waters; or
- (2) An ROW pipeline that is operated by an indentified pipeline operator . . . and that is either:
  - (i) A producing pipeline operator . . . <u>and the pipeline is not subject to regulation under 49 CFR parts 192 and 195</u>.

(ii) A transporting pipeline operator . . . <u>and the pipeline is not subject to regulation under 49 CFR parts 192 and 195</u>.

(b) DOT jurisdiction criteria. An OCS pipeline that is not under DOI jurisdiction (see paragraph (a) of this section) is under DOT jurisdiction.

(emphasis supplied).

The express exclusion of DOT-regulated pipelines accords with DOI's consultation and coordination duties under OCSLA: "In administering the provisions of this section, the Secretary [of DOI] shall consult and coordinate with the heads of other appropriate Federal departments and agencies for the purpose of assuring that, to the maximum extent practicable, inconsistent or duplicative requirements are not imposed." 43 U.S.C. § 1347(f)(1). Moreover, the exclusion of DOT-regulated pipelines preserves the distinction between "producer operated pipelines" and "transporter operated pipelines" delineated in the MOU. Proposed Rule, 72 Fed. Reg. at 56443 (referencing MOU, 62 Fed. Reg. 7037 (Feb. 14, 1997)). Finally, MMS's impact statement (pursuant to Executive Order No. 12866) suggests in paragraph (2) that the Proposed Rule is not intended to be applied to DOT-regulated pipelines:

> The Proposed Rule would not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency.
>
> Both DOI and DOT have jurisdiction over OCS oil and natural gas pipelines. These jurisdictional boundaries are defined in the Proposed Rule.

Proposed Rule, 72 Fed. Reg. at 56449.

Each of these sources and arguments suggests that MMS intended to exclude DOT-regulated pipelines, but this is where the word "all" creates confusion by suggesting an intent to apply the Proposed Rule to every OCS pipeline, whether DOT-regulated or not.

For example, in describing the regulations for pipeline surveying, MMS states "The Proposed Rule would require visual surveys of <u>all</u> pipeline routes, at least monthly . . . ." Proposed Rule, 72 Fed. Reg. at 56446 (emphasis supplied). For DOT-regulated pipelines, which conduct such inspections annually, MMS's proposed regulation threatens to increase compliance costs substantially. Perhaps MMS intended to say "The Proposed Rule would require visual surveys of all DOI-jurisdictional pipeline routes, at least monthly . . . ." If so, the issue goes away, at least as far as DOT-regulated pipelines are concerned. Until the language is changed (or at least clarified) the issue persists.

The problematic language also appears in MMS's certification under the Regulatory Flexibility Act ("RFA"), 5 U.S.C. §§ 601, *et seq.*: "This Proposed Rule applies to all lessees, designated lease operators, and pipeline ROW holders operating on the OCS." Proposed Rule, 73 Fed. Reg. 56449.

The preamble language regarding surveying, the RFA certification and similar language elsewhere color the entire Proposed Rule; thus, even when a provision does not refer to "all pipelines," parties are left to wonder whether DOT-regulated pipelines are included or not.

The difference is significant. Consider these differences between current DOT regulations (promulgated by PHMSA) and the proposed MMS counterparts:

- PHMSA requires an operator to maintain cover over pipelines offshore where water depth is less than 15 feet. By contrast, he Proposed Rule requires the maintenance of depth of cover out to 200 feet.
- PHMSA requires operators to patrol the pipelines once per year in the offshore environment. The Proposed Rule requires patrolling monthly.
- PHMSA requires operators to develop and maintain operations and maintenance procedures. The Proposed Rule would require operators to develop and maintain operations and maintenance procedures.
- PHMSA requires operators to develop and implement and Integrity Management Program for all pipelines that are in High Consequence Areas. Based on these regulations offshore pipelines, for the most part, are not within the scope of the regulations since the offshore environment is not considered by DOT to be a High Consequence Area. The proposed regulations would require Integrity Management Plans for all offshore pipelines.
- PHMSA regulations apply to offshore platforms including design and safety equipment. The proposed regulations would require operators to institute additional design

> considerations and require additional safety equipment. The proposed regulations would require certain unmanned platforms with high flow rates to be re-designed and modified to meet the modern design standards, in spite of the fact that no L-1 platforms were destroyed or damaged in Hurricanes Katrina or Rita, the worst offshore disasters in recorded history.

In a section entitled "Comments to Specific Paragraphs of the Proposed Regulations," INGAA offers further examples of MMS proposals that exceed current PMHSA requirements.

II. TERMINATING A PIPELINE'S RIGHT-OF-WAY FOR TEMPORARY CESSATION OF OPERATIONS IMPERMISSABLY CONFLICTS WITH THE GOALS OF THE OSCLA AND THE FEDERAL ENERGY REGULATORY COMMISSION'S JURISDICTION OVER FACILITIES CERTIFICATION AND ABANDONMENT.

Under the proposed regulations, a right-of-way grant will be deemed "expired" if operations cease for a period of 180 days without approval from the Regional Supervisor. Proposed Section 250.1137(c)(2). Administratively deemed expiration operates to terminate the right-of-way grant, the operator may no longer use the pipeline. Proposed Section 250.1138(a).

The proposed system of administratively determined expiration and termination conflicts with at least two provisions of the OSCLA. First, to the extent the new rules threaten the continuing viability of existing right of way grants because of a temporary cessation of gas flow, they are inconsistent with the Congressional declaration of policy. *See* 43 U.S.C. §1332(3). (favoring expeditious and orderly development of energy resources in the outer continental shelf). It is axiomatic that the needless elimination of necessary transportation options would negatively impact the development of natural resources.

Second, to the extent the Proposed Rule contemplates the termination of right-of-way grants and the decommissioning of pipelines that retain economic and developmental utility, the regulations would have the effect of requiring the installation of new pipelines in new rights of way, just to replace pipelines which, by MMS regulation, were taken out of service before there was practical justification to do so. Such needless addition of facilities would have a negative environmental impact on the OCS, fostering the very circumstances Congress passed the OSCLA to avoid. *See* 43 U.S.C. § 1332(6).

Administratively determined expiration also conflicts with the jurisdiction of the Federal Energy Regulatory Commission ("FERC") over the certification and abandonment of natural gas pipeline facilities. Once a pipeline facility (including an OCS facility) receives a FERC certificate of public convenience and necessity, that facility may not be abandoned without FERC authorization:

> No natural gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, <u>without the permission and approval</u> <u>of the Commission</u> first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

15 U.S.C. § 717f(b) (emphasis supplied). A FERC certificate is more than a permit to construct and operate. It is also an legal obligation, conferred on the pipeline, to stand ready to provide service through the certificated facilities until the FERC grants abandonment authority.

III. THE PROPOSED REGULATIONS WOULD IMPOSE $162 MILLION IN ONE-TIME COSTS AND $875 MILLION IN ANNUAL COMPLIANCE COSTS.

In its statement pursuant to Executive Order No. 12866, MMS states that the cost of the proposed regulations is not "significant," meaning the total cost will be less than $100 million. S*ee* 73 Fed. Reg. 56449. The MMS cost analysis is incomplete in that it only recognizes administrative costs and it undervalues those costs on a per-hour cost basis as well as the time needed for each activity. It ignores the cost of performing all of the proposed requirements such as the cost of patrolling pipelines once per month and the cost of in-line inspection or pressure testing pipelines as part of an Integrity Management Program.

Based on a cost analysis performed by INGAA, the actual compliance costs would be far more than those reported by MMS. Based on a member-developed cost-benefit analysis, which is attached as an appendix to these comments, the Proposed Rule as written could cost $875 million per year plus a one-time cost of $162 million to develop plans and programs.

The huge cost of the Proposed Rule traces in part to the sheer scope of the regulations.

- Each and every repair must be approved on an individual basis prior to the repair, a fee paid for processing and paperwork is required. This process is slow, cumbersome, and expensive and the pipelines remain out-of-service during this process.
- Records of each new pipeline must be provided to MMS within 45 days of completion of construction. The current rule allows 90 days. This change adds a burden to operators to compile the information, perform quality control of the information and submit to MMS. It is also unclear why all this information is needed.
- Annual fees would be adjusted from $15 per mile to $70 per mile with intent to go to $125 per mile in the future without notice. This change is costly and the justification was not provided in the Proposed Rule.
- Too much unilateral authority would be in the hands of the Regional Supervisor with no due process in the decision making and no opportunity to appeal. In addition there are not guidelines for the Regional Supervisor to follow when making decisions.

Another factor contributing to compliance costs is that the Proposed Rule is very prescriptive relative to the current, performance-based regulations. The prescriptive nature of the rule takes away flexibility that the operator needs.

Finally, the Proposed Rule has significantly more record keeping and reporting requirements than the existing rule. It also requires very rigid permitting and operating requirements. It is unclear why these changes have been made. The changes add cost to operations, require more MMS staff to process slow down processes and have not been justified in the Proposed Rule.

A section-by-section analysis of the regulations, with corresponding technical comments, follows.

SECTION-BY-SECTION COMMENTS

Overview

The MMS Subpart J Notice of the Proposed Rule has been analyzed to determine the MMS requirements for natural gas pipeline transporters as they relate to the sections listed above. The Proposed Rule requirements are extensive and reach far beyond the current Subpart J requirements for both DOT and DOI pipelines. The comments in this paper focus only on those requirements that would have a "major impact" on the natural gas transmission (transporters) industry if it was required to comply with the Proposed Rule as currently proposed. Major changes are defined as requiring a significant increase in an operator's:

- work hours or staffing in order to be in compliance or,
- either O&M or capital dollars expended to be in compliance or,
- administrative monitoring and reporting to be in compliance.

In analyzing the Proposed Rule, several themes quickly emerge. These are:

- MMS is requiring extensive record keeping and mandatory reporting
- MMS is being more conservative on required reporting time-lines and design life criteria than either they or DOT currently require
- MMS is blurring the distinction between DOT and DOI jurisdictional lines (it should be noted that the design, construction, operation, and maintenance of natural gas transmission pipelines are subject to DOT regulations as outlined in the current laws, regulations, and MOU of both the DOI and the DOT)
- MMS is incorporating previous NTL's (Notice To Leaseholders) into the Proposed Rule. (In some cases MMS is expanding the requirements beyond their existing NTL's. For example, NTL T-186 was released in August 2007 for comments and an expanded version of this NTL is included in the Proposed Rule.)
- MMS is giving broad and unilateral discretionary authority to the Regional Supervisor

Beyond the major impacts that are identified in this report, other "concerns" with the Proposed Rule are also identified. These other concerns will clearly have an impact on the gas transmission industry if it has to comply with the Proposed Rule requirements as proposed, but they aren't as onerous as the major impacts. Therefore, they are listed as concerns. It should be pointed out that there are many other "minor" concerns with Proposed Rule, including vague language, broad and confusing language, certain mandated reports, and generally accelerated notification and reporting time frames, which MMS should address before final regulations are promulgated.

Pipeline Applications
(Proposed 30 C.F.R. §§ 250.1031 – 250.1036)

<u>General Comments</u>

The information that the applicant must supply MMS in a pipeline application is spelled out, in detail, in this category. The Proposed Rule consolidates current MMS application contents and application process requirements, with related guidance from several NTL's and one LTL. For lease term pipelines, activities in the western Gulf of Mexico ("GOM") must be covered in Development Operations Coordination Documents ("DOCDs") and activities for lease term pipelines in the eastern GOM must be covered in Development and Production Plans ("DPPs"). *See generally*, 30 C.F.R. 250, subpart B, Plans and Information.

The Proposed Rule would, in large measure, impose the lease term pipeline application requirements, embodied in DOCDs and DPPs, on ROW pipeline applications. Current pipeline ROW regulations do not impose these requirements.

Pipeline Design
(Proposed 30 C.F.R. §§ 250.1031 – 250.1036)

Definition of "Design Life"

There are several requirements in the Proposed Rule where the MMS is requiring the design life of a particular system (e.g. anode system) to have a life expectancy of "X" years or for the design life of the pipeline, whichever is longer. Many systems, such as anodes, are designed for a finite life such as 20 years. However, natural gas pipelines are not designed to have a finite life. DOT Part 192 does not have a design formula or methodology for determining a "design life" on a pipeline. The life expectancy of a pipeline is determined by a number of factors including original design, ongoing maintenance, operating conditions, etc.

As to the "design life" for offshore gas transportation lines, there is not any single factor or formula for determining the design life of a pipeline. DOT Part 192 specifies a formula that determines the minimum pipe wall thickness given certain other factors (*i.e*. yield strength of the pipe, operating pressure, OD, temp, etc.) but there is no "age factor" in the formula. The overall design, maintenance, operating conditions, certain external factors and the application of the pipeline determine how long it will last. In theory, a steel pipeline that is properly designed, operated, and maintained and is transporting good quality gas can last for many decades.

As an example on the design side, the type and thickness of external and internal coatings, the cathodic protection (*i.e*. mass of anodes), the wall thickness above minimum requirements, protection from external forces, etc. are all factors that would extend the life of a pipeline. Maintenance such as ongoing testing of the efficiency of anodes and timely replacement to ensure adequate protection, painting of piping exposed to the environment, all serve to extend the life of the pipeline. Both design and maintenance tend to protect the pipeline "from the outside."

The application in which the pipeline is placed determines its life "from the inside." If a pipeline is used to move or exposed to particular substances with corrosive properties, then internal coatings (type, thickness, quality), chemical inhibitors (type, frequency, efficacy), pigging type (scraper, poly pig) and frequency all have an impact on its life. A pipeline operated near its maximum pressure for extended periods will have endured more stress than one operated at lower pressures and may be a candidate for stress related failures.

If these regulations pass as proposed, then the design life of each pipeline would very likely have to be determined in order to comply. This would be a very costly endeavor to *attempt* to calculate the design life given the lack of a "design life formula" and any attempts to determine such design life would likely require very extensive testing (i.e. – determine the remaining wall thickness). With the various factors that could be used, any such analysis could be very highly subjective since a myriad of factors come into play such as

- what products will flow through this line
- for how long
- what is the corrosivity
- will there be any low spots that *might* hold water
- how long would water be held
- what chemicals will be injected and what is their efficacy
- how often will be line be pigged
- what is the efficiency of the pigging

There are tens of thousands of miles of offshore pipelines that have been in place for decades very reliably delivering their products. These pipelines are routinely maintained and prove that pipelines can work effectively for long periods of time without having been designed for a finite life expectancy.

As mentioned earlier, the Proposed Rule states in § 250.1033(d) that a company must design its anode cathodic protection (CP) system to have a life expectancy of 30 years (versus 20 currently) or for the design life of the pipeline, which is longer. Platforms would typically have a design life longer than 30 years and it may not make sense to design the CP system for the life of the platform. The CP system can be repaired, replaced or upgraded as necessary to ensure it is working effectively. Also, technology improvements may make a CP system out-dated and it can be upgraded as necessary. Therefore, it's not practical or economic to design a CP system beyond 20, or possibly 30 years.

Pipeline Construction
(Proposed 30 C.F.R. §§ 250.1040 – 250.1051)

General Comments

The Proposed Rule contains all the MMS requirements in the current rule, plus it has added several new requirements. Most of the changes involve required notifications prior to construction, delineating the horizontal component and its protection requirements, riser protection, and specific construction requirements in or near designated use areas, sensitive biological features or areas, and near an archaeological resource. Transportation pipelines should not have to maintain the original depth of cover unless the pipeline can be reasonably determined to present a hazard to people, the environment or other OCS activities. The operator's justification must rely on industry accepted risk based principles and DOT based performance requirements, *e.g.*, 49 C.F.R. §§ 192.613 and 192.703(b).

<u>Major Impacts</u>

Burial of pipelines
Proposed 30 C.F.R. § 250.1044(d)

The Proposed Rule states that the Regional Supervisor may require the burial or other protection of the pipeline in any water depth if the Regional Supervisor determines that such measures will reduce the likelihood of environmental degradation, or mitigate a potential hazard to trawling operations of other uses of the OCS. This requirement could result in the Regional Supervisor unilaterally requiring companies to bury miles of pipelines at significant costs.

<u>Other Concerns</u>

Buoying hazards
Proposed 30 C.F.R. § 250.1042(a)

The Proposed Rule requires that before beginning construction operations or other bottom disturbing activities in areas congested with pipelines or debris, use buoys to outline a safe working area. It requires a company to buoy all existing pipelines and other potential hazards located within 500 feet of the operation, including anchor patterns. In lieu of using buoys, a company can use state-of-the art, real-time primary navigational positioning equipment to depict pipelines and other potential hazards. The concern with the requirement for buoying is one of jurisdiction. Currently, the U.S. Coast Guard is responsible for buoying requirements.

H_2S contingency planning
Proposed 30 C.F.R. § 250.1050

The Proposed Rule requires a company to prepare an H_2S Contingency Plan before it constructs a pipeline (using an anchor-supported construction vessel) that crosses a pipeline which transports a product with an H_2S concentration that if released could result in atmospheric concentrations of 20 ppm or more. It would be an administrative burden for pipelines to contact each pipeline it crosses during construction to ascertain whether or not they transport H_2S and if it were released to the atmosphere would it exceed the 20 ppm threshold. It would be simpler and more effective if the MMS would ask each pipeline that currently transports H_2S where an atmospheric release could exceed the threshold to identify those specific pipelines to the MMS. A database of those pipelines could be maintained by MMS and accessed by companies before construction proceeds to determine if any pipeline being crossed would require a contingency plan to be developed. MMS could require companies to update their H_2S pipelines annually to make sure their database remains current. MMS could capture this data for new pipelines that are being constructed as part of the construction permitting process.

Pipeline Pressure Testing
(Proposed 30 C.F.R. §§ 250.1057 – 250.1061)

Major Impacts

Hydrostatic pressure test after making a repair with a clamp
Proposed 30 C.F.R. § 250.1060(b)

The Proposed Rule requires that before a company can return a pipeline to service following a repair using either a mechanical or welded clamp it must successfully perform one of two leak tests. Typically, a welded clamp repair will be used above water and a mechanical clamp repair used below water. The latter repair requires a leak-test of the pipeline, including the riser or risers, or if required by the Regional Supervisor an 8-hour hydrostatic pressure test of the pipeline, including the riser or risers. In most cases, isolating the riser or risers where the clamp has to placed in order to perform a hydrostatic pressure test is extremely difficult and not practical. For the former, it's often difficult to isolate the section where the clamp was placed and, in many cases, would result in pressure testing miles of pipeline in order to pressure test the welded clamp. Additionally, DOT doesn't require the pressure testing of pipelines or risers repaired with clamps. Using clamps for repairs is a routine and common practice today in order to expedite repairs and minimize service impacts. This Proposed Rule requirement would have a significant cost impact to the industry. Pipeline repair requirements are adequately covered by DOT regulations.

Taking a pipeline out of service
Proposed 30 C.F.R. §250.1086

The Proposed Rule defines out of service as "a pipeline that has not been used to transport oil, natural gas, sulphur, or produced water for more than 30 consecutive days. The out of service period begins on the 31st day of inactivity." This is almost the same language in the current MMS requirements. On the 31st day on inactivity, the Proposed Rule requires a company to immediately equip the out-of-service pipeline with either a blind flange or block valve locked in the closed position at each end. After a year but less than 3 years, a company must flush and fill the pipeline with inhibited seawater and after 5 years the pipeline has to be decommissioned.

The current language related to out-of-service pipelines is targeted to pipelines under the jurisdiction of DOI and the required actions are only for DOI pipelines. The Proposed Rule makes no distinction between DOI or DOT pipelines, implying that pipelines currently under DOT jurisdiction would be required to follow this Proposed Rule requirement. It's not unusual for natural gas pipelines to temporarily have lines that aren't flowing or that have been temporarily abandoned. The Proposed Rule makes no distinction between an abandoned line and an out-of-service line. The Proposed Rule appears also to go beyond the recent (August 2007) NTL concerning pipeline decommissioning.

Transportation pipeline abandonment and deactivation requirements are adequately covered by DOT regulations. Under DOT regulations, a pipeline is not considered abandoned, unused or "out of service" if it is periodically transporting gas or being actively maintained with reasonable anticipation of future use.

Other Concerns

Definition of MAOP
Proposed 30 C.F.R. §§ 250.1000, .1058, .1030(a)(2), *et al*.

MMS defines MAOP as the highest operating pressure allowable at any point in a pipeline. This is different than the DOT definition, which creates inconsistency in addition to jurisdiction concerns. It appears that MMS equates MAOP with MOP; the two are clearly different. MOP is not mentioned in DOT Part 192 but is an accepted industry term basically meaning the maximum pressure at which an interconnected system of pipelines can be operated based on the pipeline with the lowest MAOP of all pipelines in they system. When interconnected pipelines have different MAOP's, the system operating pressure is limited by the pipeline with the lowest MAOP, which is the system MOP. The MOP is always less than or equal to the MAOP.

Pipeline Leak Detection
(Proposed 30 C.F.R. § 250.1071)

General Comments

This is a short section in the Proposed Rule and in the current requirements specifically is targeted at only oil pipelines. The Proposed Rule expands leak detection to any "pipeline that transports liquid hydrocarbons to shore." Many of the gas transportation pipelines are wet or two-phase systems that transport some liquid hydrocarbons. Depending on certain operating conditions, dry systems can have liquid hydrocarbons fall out of the gas stream.

Major Impacts

Those natural gas pipelines that do transport liquid hydrocarbons to shore would be significantly impacted by this section. Those pipelines would be required to use a computational pipeline monitoring (CPM) system or equivalent methodology to detect leaks by continuously determining or calculating the imbalance between the incoming (receipt) and outgoing (delivery) volumes of a pipeline. A CPM system means an algorithmic monitoring tool that allows a company to respond to a pipeline operating anomaly that may indicate a release of hydrocarbons. The company must equip the CPM system with an alarm that signals when the imbalance exceeds a predetermined threshold for a selected time interval; and use SCADA technology to gather, process, and display the data the company uses in their CPM system.

The cost of installing such a system would be prohibitive. Additionally, gas transportation pipelines are not transporting liquid hydrocarbons as their primary product. Liquid hydrocarbons are sometimes found in the gas stream or may fall out of the gas stream during transportation due to temperature and pressure changes. Consequently, it's difficult to determine the incoming (receipt) and outgoing (delivery) volumes of such a pipeline.

It is clear that the primary intention of this section is for oil pipelines and not gas transportation pipelines and the Proposed Rule should be revised accordingly.

Pipeline Internal Corrosion and Flow Assurance
(Proposed 30 C.F.R. §§ 250.1074 – 250.1075)

General Comments

This is a new section and not found in the current requirements. It requires companies to establish and implement internal corrosion control measures as well as establish and implement measures to ensure that adequate flow can be sustained throughout the service life of the pipeline under all expected flow conditions.

Major Impacts

Internal Corrosion Control Measures
Proposed 30 C.F.R. § 250.1075

The Proposed Rule requires a company to establish and implement internal control measures (*e.g*. running pipeline scrappers; dehydrating; using corrosion inhibitors, bactericides, or oxygen scavengers) to protect the pipeline over its service life. This would imply these measures are required whether or not a corrosive environment is present. This is much broader than current DOT requirements and would be costly to implement and maintain such a program on all pipelines. A corrosion control program is a good idea when a corrosive environment is present. Most operators have developed cost-effective programs of their own, as part of their maintenance procedures to effectively mitigate internal corrosion of offshore pipelines. Corrosion control requirements are adequately covered by DOT regulations.

Other Concerns

Low Flow from Producer Lines

The Proposed Rule requires a company to ensure that adequate flow can be sustained throughout the service life of the pipeline under all expected flow conditions and for the range of pressures. There are many pipelines where over the years the production is largely depleted and little gas flows through the lines. The flows and pressures are often too low to run pigs and the producers, who control the flow, usually don't want to de-commission the line. Flow control and others issues that affect the integrity of a transportation pipeline are covered by DOT regulations.

Pipeline Safety Equipment
(Proposed 30 C.F.R. §§ 250.1062 – 250.1069)

General Comments

Safety related equipment is addressed to a large degree in the current requirements as applicable to DOI pipelines. The Proposed Rule has more detailed language regarding safety equipment, includes some new items like manned platforms, maximum source pressure, etc. The Proposed Rule defines safety related equipment as:

- pressure safety high and low sensors
- flow safety valves
- subsea tie-in block valves
- shut down valves
- surface safety valves
- pipeline pumps (mentions API requirements; should apply only to oil pipelines)

Gas transportation pipeline safety equipment requirements are adequately covered by DOT regulations.

Other Concerns

Suspending Operations
Proposed 30 C.F.R. § 250.1069

The Proposed Rule states that if safety equipment fails, the operator must immediately suspend operations and shut-in the pipeline. The current requirements do not call for immediately shutting-in the pipeline. Shutting-in the pipeline would normally be done to possibly prevent a product release or to make the necessary repair. However, the Proposed Rule also calls for notifying the Regional Supervisor if the safety repairs will result in the pipeline being out-of-service for more than two hours. Also, if an operator shuts in a pipeline due to the safety equipment being out-of-service for more than two hours, the operator must submit a detailed repair application and receive approval from the Regional Supervisor before any repair work can begin. This requirement is overly burdensome, unnecessary and could result in unwarranted delays in getting a pipeline back into service. Operations, maintenance, and emergency response requirements for gas transportation pipelines are adequately covered by DOT regulations.

Pipeline Operations and Maintenance
(Proposed 30 C.F.R. §§ 250.1078 – 250.1091)

General Comments

This section of the Proposed Rule is expanded significantly beyond the current requirements. Among the more significant changes, MMS is requiring an expansion of the

Operations and Maintenance ("O&M") manual, a management integrity program, emergency operating plans, operator qualification programs, H_2S contingency plans, and pipeline safety equipment testing. It appears MMS is adopting some of the DOT requirements, like integrity management, but from a totally difference perspective.

<u>Major Impacts</u>

Maintaining Approved Burial Depth after Decommissioning
Proposed 30 C.F.R. § 250.1078(d)

This is not a requirement or practice today. A company faces significant challenges in maintaining the approved burial depth of many pipelines throughout the life of the pipelines. This would require a company that discovers that any of its pipelines aren't at the approved depth to rebury the pipeline immediately. For example, if a pipeline was approved to be at a three foot depth and it's now at a 2.5 foot depth, it would have to be reburied. Complying with this requirement would be impractical, time consuming and very costly and unnecessary.

Natural gas transportation pipelines should not have to maintain the original depth of cover unless the pipeline can be reasonably determined to present a hazard to people, the environment or other OCS activities. The operator's justification must rely on industry accepted risk based principles and DOT based performance requirements (*i.e.*, 49 C.F.R. §§ 192.613 and 192.703(b)).

Integrity Management Program
Proposed 30 C.F.R. § 250.1079(b)

The Proposed Rule calls for a written pipeline integrity management plan ("IMP") for all OCS pipelines that includes numerous components including pigging all pipelines. Today, the DOT requires an integrity management plan only in High Consequence Areas ("HCAs"). The DOT integrity management program is logically targeted at protecting the general public in HCAs, where the risks and consequences are the greatest. An offshore integrity management program serves no such public safety concern (beyond any offshore HCA areas) and would be impractical with little or no perceived benefit in terms of safety or efficiency.

Evacuation and Shut-In
Proposed 30 C.F.R. § 250.1083

Under the Proposed Rule, if a platform is evacuated due to weather or emergency the operator is required to shut-in any connecting pipeline unless there is remote operations capability. Furthermore, during an evacuation one can conduct remote operations on the pipeline only if: (a) the Regional Supervisor has given the operator prior approval; (b) the operator has remote monitoring and shut-in capability; and, (c) the company's circuitry, included in the SCADA logic, that has local storm timers designed to shut-in a pipeline no more than 4 hours after the capability to monitor and control a process is lost.

When evacuating their platforms, natural gas pipeline companies rarely shut-in anyone. The decision to shut-in production or flow is made by the producer. Furthermore, most natural gas pipelines don't have full remote shut-in capability, and they would therefore have to shut-in production under the Proposed Rule. Shutting in the pipelines, depending on the number of platforms evacuated, could have an enormous impact of the deliverability coming out of the Gulf. Adding remote monitoring and shut-in capability that's integrated into a company's SCADA system would be very costly.

Emergency response and preparedness is already required by DOT regulations. Offshore gas transportation operators have well tested hurricane evacuation plans and other site specific contingency plans as required by the DOT.

Pipeline Safety Equipment Testing Requirements
Proposed 30 C.F.R. § 250.1084

The Proposed Rule requires testing of safety related equipment on monthly or annually basis depending on the safety device. For example, check valves are not inspected today, but would have to be inspected annually, not to exceed 13 months (DOT is typically 15 months). Similarly, shut-down valves must be inspected monthly and fully-closed annually. Conducting these inspections is impractical and would have significant manpower impacts on the operators with no added safety benefits. Inspection and maintenance requirements are adequately covered by DOT regulations.

MMS Suspension or Prohibition of Pipeline Operations
Proposed 30 C.F.R. § 250.1091

The Proposed Rule give the Regional Supervisor unilateral authority to suspend or temporarily prohibit any pipeline operations if the Supervisor determines that continued activity would threaten or result in serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, mineral resources; or the marine, coastal or human environment. Also, if the Regional Supervisor determines a company has failed to comply with a provision of the OCSLA or any other applicable law, a provision of this part or other applicable regulations, or a condition of a pipeline application approval or of a pipeline ROW grant; or protecting the nation's security, the Regional Supervisor can suspend or temporarily prohibit any pipeline operations. There appears to be no graduated enforcement mechanisms, *e.g.*, warnings or fines, nor is there any type of an appeal process (unlike DOT). The judgment of safety and operations of DOT pipeline activities is covered under the Pipeline Safety Act and not the OCLSA.

Pipeline Modifications and Repair
(Proposed 30 C.F.R. §§ 250.1093 – 250.1097)

<u>General Comments</u>

Similar to the other sections of the Proposed Rule, this section has added some wording changes and reporting requirements. The definition of what comprises a modification has been expanded to include installing or replacing a pig receiving/launching facility; changing a pipeline riser configuration; changing the MAOP; replacing or adding anodes; and adding a hot-tap.

Major Impacts

The Proposed Rule would require an application to the Regional Supervisor for approval to make a permanent repair when a mechanical clamp is used to temporarily repair a riser in or above the splash zone. Operators would be required within 30 calendar days after they install the mechanical clamp to complete the permanent repair using a welded clamp, spool piece, or other method approved by the Regional Supervisor. DOT does not require this today and at times the use of a mechanical clamp is an accepted practice to expedite a repair or maintain deliverability.

Other Concerns

Repair Commencement and Completion
Proposed 30 C.F.R. § 250.1095

The Proposed Rule requires a company to submit an application to the Regional Supervisor for approval before any modifications or repair work on a pipeline can commence. Today, under the current requirements the Regional Supervisor may require a detailed repair procedure be submitted prior to conducting the work. Currently a company must notify the Regional Supervisor before the repair of the pipeline or as soon as practicable along with a detailed report of the repairs within 30 days after completion of the work. The Proposed Rule requires an even more detailed repair application that has to be submitted at the same time as the notification to the Regional Supervisor.

The Regional Supervisor may also require the company to submit a work plan that describes specific measures it intends to take, and the specific procedures it intends to follow, to ensure the safety of offshore workers and to prevent pollution. The Regional Supervisor may also require a company to analyze a pipeline failure, and examine samples of a failed pipe or associated equipment in a laboratory to determine the cause of the failure. When so directed, the company must submit a comprehensive written report of its findings to the Regional Supervisor.

Additionally, the Regional Supervisor may require a company to submit a corrective action plan for approval, if there are internal or external conditions that could detrimentally affect a pipeline. Having to get approval from and submit a detailed application to the Regional Supervisor before any repair work can commence will impede a company's ability to quickly restore service thereby affecting deliverability and reliability.

Pipeline Surveying, Monitoring, and Inspection
Proposed 30 C.F.R. §§ 250.1100 – 250.1103

General Comments

The Proposed Rule takes a current requirement for DOI pipelines to inspect its pipelines monthly for leakages and applies it to all pipelines. It also requires time based inspections on other pipeline components.

Major Impacts

Pipeline Route Surveys
Proposed 30 C.F.R. § 250.1101

The Proposed Rule says a company must conduct a visual survey of each of its pipeline routes at least monthly (or at a frequency specified by the Regional Supervisor) for indication of pipeline leaks. Currently, natural gas pipelines patrol their offshore lines annually for leaks. A monthly requirement would have an enormous manpower and cost impact on companies. Helicopters and boats in the OCS are constantly checking for leaks as they go about their normal daily activities and offshore leaks are easily detected by bubbles on the surface. Natural gas leaks aren't harmful to the environment and there is no reason to patrol monthly for leaks. Pipeline patrols and leak surveys are adequately covered under DOT regulations.

Pipeline Right-of-Way (ROW) Grants
Proposed 30 C.F.R. §§ 250.1115 – 250.1138

General Comments

This section of the Proposed Rule covers the terms and conditions for holding a pipeline ROW grant, including when a grant is needed, who may hold a grant, and how to apply for a grant. It also covers: bonding, application submittal, MMS review, compliance, environmental review, state consistency review, modifications, and cessation of operations, assigning a grant, suspensions, relinquishing a grant, and terminating a grant.

Because of certain administrative similarities between pipeline ROW grants and OCS leases, many of the proposed changes are based on or derived from the regulations in 30 CFR Part 256, which addresses OCS leasing. Each separate ROW pipeline requires a separate ROW grant. The proposed financial security requirements are more detailed than in the current regulations. Currently, pipeline companies must furnish an area bond in the amount of $300,000 to hold pipeline ROW grants in an MMS OCS region. The Proposed Rule would allow a pipeline ROW holder the option of choosing to cover the pipeline ROW with either a $300,000 pipeline ROW grant individual bond or a $1,000,000 pipeline ROW grant bond. The $1,000,000 area bond will cover all pipeline ROW grants held by a company in one MMS OCS region.

These requirements represent an increase from the current bonding amount, and will more accurately reflect the actual liabilities in decommissioning pipelines. The new proposed amounts would apply to all existing and future grants. Companies would be required to cover existing pipeline ROW grants by these increased amounts within 6 months after the rule becomes effective.

The Regional Director may also require additional security based on an evaluation of a company's ability to carry out present and future financial obligations under the pipeline ROW grant. Companies have the opportunity to provide MMS with written or oral arguments during the evaluation. These securities are required primarily to ensure that the U.S. Government has sufficient funds available to properly decommission a pipeline in the event that the pipeline company is unable or unwilling to do so. The Proposed Rule includes language giving MMS the ability to reduce the amount required by a bond, to deal with lapse in bonds, and to determine bond forfeiture.

The service fee for a pipeline ROW grant would remain unchanged. The Proposed Rule addresses pipeline ROW grant assignments. The conditions for when MMS would suspend a ROW grant are spelled out more clearly.

The MMS is proposing to increase the annual rental fees for pipeline ROW grants to reflect the current rates established for new rights-of-use and easement, *see*, 30 C.F.R. §§ 250.160(f) and (g)) and pipeline accessory structures *see*, 30 CFR 250.1012(b). The amount established by these regulations are $5.00 per acre per year for sites in water depths less than 200 meters and $7.50 per acre per year for sites in water depths 200 meters or greater. The current rental rate for pipeline ROW grants is $15 per mile. A pipeline ROW is 200 feet wide. Therefore the area of a pipeline ROW grant is 24.24 acres per mile. At $5.00 per acre, the rental rate would be approximately $125 per mile (actually $121.20).

Since raising the rental for pipeline ROW grants to $125 per mile from $15 per mile is a major increase, MMS is proposing to raise the rental in two steps. This Proposed Rule would increase the annual rental for pipeline ROW grants to $70 per mile. MMS will propose the second increase to $125 per mile in a future rule making. Although this is a large increase, MMS believes the higher fee is a fair and reasonable amount to pay for access to Federal lands.

Accessories to Right-of-Way (ROW) Pipelines Category
Proposed 30 C.F.R. §§ 250.1140 – 250.1147

<u>General Comments</u>

The Proposed Rule expands the current subpart J regulations for accessories to ROW pipelines. However, there are very few new requirements in Subpart I. The new requirement here is the application of Subpart I to DOT transportation (accessory) platforms (or ROW platforms) in regard to operation, inspection and maintenance requirements. This would also require existing platforms to be redesigned or modified to meet modern requirements if deemed appropriate by MMS. DOT operators currently apply the inspection and maintenance requirements under the industry standard API RP 2A, which also includes grandfather provisions relating to design and construction requirements.

The Proposed Rule also specifies that accessories to ROW pipelines are subject to the requirements currently contained in 30 CFR 250, subpart H, Oil and Gas Production Safety Systems, which has not previously been applied to DOT regulated facilities on accessory platforms. Safety systems such as overpressure protection and emergency shutdown of DOT pipelines are already subject to the DOT Pipeline Safety regulations on accessory platforms.

CONCLUSION

In light of the facts and arguments presented above, INGAA requests MMS to clarify that the regulations promulgated in the Proposed Rule do not apply to natural gas transportation pipelines subject to DOT regulation. If and to the extent MMS intends for these regulations to apply to DOT-regulated natural gas pipelines, INGAA requests the Commission revise its proposed regulations to address the concerns expressed in the section-by-section analysis above.

Respectfully submitted,

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APPENDIX

COST AND BENEFIT ANALYSIS

The information discussed in this section is based on a review of the MMS cost analysis and input from several INGAA member companies. The cost information provided by MMS does not agree with company experience and expectations for the identified activities. INGAA believes the hours were significantly underestimated as was the per hour cost. In addition, the MMS analysis of costs only addressed expected administrative burden and did not address the costs to actually perform the identified activities such as patrolling, burying pipelines, and integrity assessment.

Based on the analysis provided below, INGAA believes the Proposed Rule is not cost justifiable, would place an extreme and unnecessary burden on the energy pipeline transportation industry and would not provide a benefit to the operator or the public.

Cost Analysis

<u>Reporting</u>

INGAA estimates the total hour burden to develop systems, reports and records, perform quality control, and obtain management approval and legal review to be 117,600 hours with an associated cost of **$8,820,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 20 hours for general departure and compliance requests
- 500 hours to retain all records and make available to MMS
- 400 hours to generate a petition to change jurisdiction
- 20 hours to mark DOI/DOT interface and note of records

<u>Forms</u>

INGAA estimates the total hour burden to complete forms, perform quality control, and obtain management approval and legal review to be 38,900 with an associated cost of **$2,917,000.** This cost is based on an average hours as shown below with a $75/hour rate:

- 20 hours for each notice under 1041(c), 1058(b) and 1093(f)
- 10 hours for completion and submission of form MMS-2030
- 120 hours to submit form MMS-2030
- 120 hours to submit form MMS-149

Applications for New Pipelines

INGAA estimates the total hour burden to develop applications, perform quality control, and obtain management approval and legal review to be 423,000 hours with an associated cost of **$31,725,000**. This cost is based on average hours as shown below with a $75/hour rate:

- 800 hours to prepare and submit applications
- 20 hours impacted lessees
- 300 hours to submit third party review

Pipeline Design and Construction

INGAA estimates the total hour burden to develop agreements and notifications, perform quality control, and obtain management approval and legal review to be 49,600 hours with an associated cost of **$3,712,500**. This cost is based on average hours as shown below with a $75/hour rate:

- 20 hours to prepare notifications to military
- 40 hours for buoy hazards
- 100 hours to enter into agreements with command headquarters
- 120 hours to submit construction reports

Pipeline Risers Connected to Floating Platforms

INGAA estimates the total hour burden to develop, perform quality control, and obtain management approval and legal review to be 52,800 hours with an associated cost of **$3,960,000**. This cost is based on average hours as shown below with a $75/hour rate:

- 240 hours to develop and submit riser verification plans
- 240 hours to submit final reports on design and construction

Pipeline Testing, Safety, Leak Detection, Operations and Maintenance

INGAA estimates the total hour burden to develop the required programs and plans, perform quality control, and obtain management approval and legal review to be 2,162,800 hours with an associated cost of **$162,200,000**. This is a one time cost and is based on average hours with a $75/hour rate.

In addition INGAA estimates that the ongoing annual cost associated with these sections of the regulations is based on an hour burden of 404,000 with an associated cost of **$30,300,000** for the ongoing administrative burden to carry out the tasks and document.

Not mentioned by MMS is the cost to maintain cover to the amounts specified in proposed section 250.1078. The cost to rebury pipeline is estimated at $50,000 per mile. Based on an estimated re-burial need every ten years and considering the amount of pipe in the OCS, the annual cost is estimated at **$165,000,000**.

Not mentioned by MMS is the cost to perform the required activities that will be required once the Pipeline Integrity Program is developed. INGAA has recently completed a cost analysis for the DOT required Integrity Management Program which was used by INGAA in Congressional Testimony in March of 2008. Based on actual cost information collected by INGAA for its members, the DOT required integrity management program has cost the gas transportation industry $1.564 billion over 5 years to assess 4,847 miles of high consequence area (HCA) pipeline. This equates to a cost per mile of HCA pipeline of $322,000. Given this cost and applying it to all OCS pipelines, INGAA estimates that there could be a $1.062 billion annual cost over a ten year period ($322,000 per mile times 33,000 miles of OCS pipe is $10.62 billion divided by 10 years is $1.062 million per year) to add valve platforms, make the pipeline piggable, conduct pigging with in-line inspection devices and perform prevention and mitigation tasks as may be necessary. This cost is based on actual costs that operators have encountered implementing pipeline integrity programs for DOT. The costs for the integrity management program include modification of facilities to accommodate smart pigs, and performing the pigging operations.

INGAA recognizes that this total cost may overstate the actual cost that may be incurred by its member companies, however even dividing the number by a factor of two; the cost could be **$531,000,000** per year. INGAA estimates that several hundred new valve platforms will need to be installed to provide for pigging operations. The cost for such a platform is estimated at $12,000,000 and includes the platform, launchers, receivers, necessary valves and controls. The costs of platforms alone would be over $2 billion and are part of the overall costs shown above.

<u>Pipeline Modifications and Repairs</u>

INGAA estimates the total hour burden to develop applications and notifications, perform quality control, and obtain management approval and legal review to be 70,000 hours with an associated cost of **$5,250,000**. This cost is based on average hours as shown below with a $75/hour rate:

- 120 hours to submit application for modification
- 40 hours to submit modification report, application to repair and repair report
- 240 hours to analyze pipeline failures

<u>Pipeline Surveying, Monitoring and Inspection</u>

MMS did not account for the cost of equipment such as boats, barges and aircraft to perform the surveys and inspections. This type of work is difficult to estimate based on hours and therefore, INGAA estimated the costs based on typical service charges. For example the cost to patrol using aircraft is approximately $100 per mile. Performing the survey 24 times per year for 33,000 mile of pipe equates to a cost of **$59,400,000** per year.

Inspection of the various portions of pipeline risers involves vessels, equipment and personnel. The costs associated with the activities include vessel rental, diving and other equipment rental, diver and other personnel costs and involve many hours of transit time to and from the platforms. Based on a daily cost and the number of platforms involved, the cost for these inspections is estimated at **$15,200,000** per year

Pipeline Decommissioning

INGAA estimates the total hour burden to develop decommissioning plans and applications, perform quality control, and obtain management approval and legal review to be 39,600 hours with an associated cost of **$2,970,000**. This cost is based on average hours as shown below with a $75/hour rate:

- 80 hours to submit application
- 40 hours to submit decommissioning report
- 120 hours to submit application to re-commission
- 120 hours to submit re-activation report

The costs to purge, flush and fill pipelines and maintain associated records are not fully explained in the MMS cost estimate. The costs to develop a decommissioning plan, purge the pipeline, flush the pipeline, dispose of the flushing material, filling the pipeline, and isolating from sources of product is estimated to be approximately $120,000. The total costs based on 300 events are estimated at **$36,000,000** per year.

Pipeline ROW Grants

INGAA estimates the total hour burden to develop applications and submissions, perform quality control, and obtain management approval and legal review to be 45,920 hours with an associated cost of **$3,444,000**. This cost is based on average hours as shown below with a $75/hour rate:

- 240 hours to submit the application
- 120 hours to submit arguments
- 40 hours to survey the pipeline
- 120 hours to submit application to modify grants and relinquish grants

Accessories to ROW Pipelines

INGAA estimates the total hour burden to develop applications and notifications, perform quality control, and obtain management approval and legal review to be 36,900 hours with an associated cost of **$2,767,000**. This cost is based on average hours as shown below with a $75/hour rate:

- 240 hours to submit application
- 240 hours to submit annual report
- 2,920 hours to inspect accessories for pollution

Proposed 30 C.F.R. Part 256

INGAA estimates the total hour burden to develop reports, perform quality control, and obtain management approval and legal review to be 30,000 hours with an associated cost of **$2,250,000**. This cost is based on average hours as shown below with a $75/hour rate:

- 20 hours to develop and submit report

Benefit Analysis

The MMS has not provided any information in the Proposed Rule that states the benefit of the new regulations. For the years 2006 and 2007, as reported to DOT for OCS pipeline incidents there was approximately $600 thousand of gas loss per year, $11.3 million of company costs to affect repairs per year and no cost to the public. This is for the approximately 14,000 miles of DOT jurisdictional pipe. The costs for 2005 were significantly higher due to two major hurricanes in the Gulf of Mexico. The gas loss cost that year was $11.4 million with the company costs of repairs being $74.6 million and no costs to the public. A four year average (2004 to 2007) shows an average per year gas loss cost of $4.3 million, an average per year for company repair and any clean up cost of $29.5 million with no costs to the public. During this period there were no fatalities or injuries reported to DOT.

A reduction of incidents and related costs may be achieved through the implementation of some of the proposed programs such as an integrity management program. If incidents could be reduced by 20 % (two-thirds of the corrosion related incidents), this would relate to an estimated cost savings of approximately $2.4 million (20% of $11.9 million, 2006 and 2007 average gas loss and company repair costs). A cost benefit can be determined based on these numbers with the cost exceeding the benefit by a factor of approximately 433 ($1.04 billion divided by $2.4 million).

INGAA has reviewed the information on gas transportation incidents and leaks reported to DOT. Incidents are reported in writing within 30 days of the incident. Leak information is reported annually. Information on reportable incidents submitted to DOT shows the following as causes:

- 31% due to internal corrosion with most of these being small pits
- 27% due to heavy rains and floods with most of these during the 2005 hurricanes
- 11% were categorized as miscellaneous or unknown
- 9% due to damage by aquatic vehicle
- 6% were component failures
- 16% due to several other causes

Information on the annual leak report information submitted to DOT shows the following causes:

- 40% due to corrosion with most of these being small internal corrosion pits
- 27% due to natural forces with most of these during the 2005 hurricanes
- 11% due to excavation damage
- 9% due to materials and welds
- 13% due to several other causes

Implementation of the Proposed Rule would have a negligible impact on the number and related costs of incidents. Even if the incidents could be reduced by 20% (two-thirds of the corrosion related incidents), this relates to an estimated benefit of $2.4 million per year for the gas transportation pipelines. There were no fatalities or injuries during the analysis years for the transportation of gas in the OCS.

Over the time period 2004 to 2007 which includes the hurricanes of 2005, there were no fatalities reported, nor were there any injuries reported. The incidents were reported to DOT were all reported because of the cost threshold of $50,000.

The average cost of gas lost for this time period was $4.3 million per year. The average cost to repair facilities due to incidents was $29.5 million per year. The average for two years, 2006 and 2007 (exclude 2005 when two major hurricanes cause damage), were $600 thousand per year for gas lost and $11.3 million per year for company cost to affect repairs.

Conclusion

Based on the estimated benefit to gas transportation operators, the cost/benefit for year one is 181 to 1 and for subsequent years 153 to 1.